Appendix C
Uncertainty Analysis of Emissions Estimates

Overview

The *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*,[1] as established at the UNFCCC 4th Conference of the Parties in Kyoto, Japan in December 1997, recommend that nations carry out analyses to estimate the uncertainty in their national greenhouse gas emissions inventories. According to the guidelines, nations should construct 95 percent confidence intervals for their greenhouse gas emission estimates using classical sampling techniques, Monte Carlo techniques, or assessments by national experts. The UNFCCC subsequently requested that the IPCC complete its work on uncertainty and prepare a report on good practice in inventory management. In 2000, the IPCC issued its report *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*.[2] The report established Tier 1 and Tier 2 methods of estimating uncertainty in greenhouse gas inventories as follows:[3]

Tier 1: Estimation of uncertainties by source category using error propagation equations ... and simple combination of uncertainties by source category to estimate overall uncertainty for one year and the uncertainty in the trend.

Tier 2: Estimation of uncertainties by source category using Monte Carlo analysis, followed by the use of Monte Carlo techniques to estimate overall uncertainty for one year and the uncertainty in the trend.

In response to the IPCC's good practices guidelines, EIA in 1998 carried out a Tier 1 uncertainty analysis of U.S. greenhouse gas emissions. This was done for carbon dioxide, methane, nitrous oxide, and other gases. The results of this analysis can be found in Table C1 below. The Tier 1 analysis provides a "weighted uncertainty" for each source calculated as the squared root of the sum of the squared activity factor and emission factor errors multiplied by the point estimate of the share of total emissions for the source. The Tier 1 approach, however, as pointed out by the IPCC may be inappropriate when combining non-normal distributions, as may be the case with some of the distributions for emissions factors and activity data.

In the 2000 to 2001 timeframe, EIA undertook a "Tier 2" uncertainty analysis of U.S. carbon dioxide, methane and nitrous oxide emission estimates to augment its previous "Tier 1" uncertainty analysis. The Tier 2 uncertainty analysis involves Monte Carlo simulations that facilitate the combination of various types of probability density functions. This analysis involved 1999 data, but the uncertainty would be consistent with the uncertainty associated with emissions estimates for the near to medium term.

Both Tier 1 and Tier 2 methods are discussed in detail below. However, they share some attributes in common. For either "Tier I" or "Tier II" analysis the sources of uncertainty fall into the following categories:

- Uncertainty associated with underlying activity data and uncertainty associated with emissions factors
- Random errors and bias errors
- Potential for upward and downward bias errors
- Reliability of emissions estimates by source.

The Tier 1 uncertainty analysis found in Table C1 excludes estimates for emissions and sequestration from land use changes and forestry. The Tier 1 analysis concluded that U.S. national greenhouse gas emissions, taken as a group, may differ by as much as 13 percent from the estimates published in the earlier edition of this report. Much of the uncertainty in national emissions was attributable to estimates of nitrous oxide emissions. If nitrous oxide emissions were excluded, the uncertainty of the total estimate was calculated to be on the order of 10 percent. As a point of comparison, the Tier 2 analysis, estimated total uncertainty about a simulated mean of total carbon dioxide,

[1]Intergovernmental Panel on Climate Change, Revised 1996 !PCC Guidelines for National Greenhouse Gas Inventories, 1997.
[2]Intergovernmental Panel on Climate Change, Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, May 2000.
[3]Intergovernmental Panel on Climate Change, Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, May 2000, p. 6.12.

methane and nitrous oxide emissions to be -4.4% to 4.6%. When expressed as a percentage of total estimated 1999 emissions[4], the uncertainty becomes -0.4 to 9.0%.

The bulk of the potential uncertainty in the overall national estimate takes the form of bias errors, which are likely to persist from one year to the next and, thus, have relatively little influence on trends, rather than random errors, which would increase the difficulty of determining whether or not a trend exists. This is because estimates of energy-related carbon dioxide are probably accurate to well within 10 percent of estimated emissions, and energy-related carbon dioxide accounts for 81 percent of national emissions of greenhouse gases. There are much larger uncertainties for methane and, particularly, for nitrous oxide emissions, but the present evidence suggests that emissions from these sources account for only a small portion of total emissions.

The uncertainties in the estimates presented in this report come from the following sources:

- **Evolving Definitions.** In general, this report attempts to measure "anthropogenic" (human-caused) emissions of greenhouse gases in the United States, excluding carbon emissions of biological origin. Although in most cases it is obvious whether emissions from a particular source fall within this definition, there are a number of ambiguous cases, and the range of accepted definitions has shifted over time. Since the first edition of this report, sulfur hexafluoride has been added to the generally accepted definition of "greenhouse gases." Emissions from bunker fuels are now excluded from the definition of "U.S. emissions." Definitional changes tend to raise or lower emission estimates systematically.

- **Emissions Sources Excluded From the Report.** An estimate that excludes some sources will be biased downward by the amount of the excluded source. Of course, if the existence or magnitude of the excluded emissions were known, they would be included. But it is probable that there are still sources that have not yet been identified and escape inclusion in both the estimates and the list of sources excluded.

- **Incorrect Models of Emissions Processes.** An estimate based on a belief that emissions are caused by (or can be estimated from) a particular activity or process can produce large, systematically biased errors if the emissions are actually caused by some other process. The incorrect method can produce estimates that are considerably higher or lower than actual emissions and have different time-series properties.

- **Errors in Emissions Factors.** Errors in emissions factors can have diverse causes, the most common of which are definitional errors, sampling errors, and measurement errors. These errors can be either random or systematic. (See discussion of carbon coefficients below).

- **Errors in Activity Data.** Activity data are also subject to definitional errors, frame errors, sampling errors, and measurement errors, which can be either random or systematic.

- **Computational Errors.** Computational errors can exist in the estimation of emissions factors by EIA, in the calculation of emissions by EIA, or in the computation of the underlying activity data by the source organization.

Although any single computational error will usually produce a systematic error, computational errors as a group tend to produce very small (about 0.1 percent) random errors in the estimate.

[4]Total 1999 emissions of carbon dioxide, methane and nitrous oxide as estimated in *EIA, Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99), October 2000.

Table C1. Estimate of the Reliability of 1999 U.S. Emissions Estimates (Tier 1 Method)

Greenhouse Gas Source	Share of Total Emissions	Activity Data			Emissions Factor			Weighted by Total Emissions	
		Bias			Bias				
		Min	Max	Random	Min	Max	Random	Min	Max
	Percent of Source							Percent of Total	
Carbon Dioxide									
Petroleum	35.2%	2.1%	2.4%	0.5%	1.7%	1.7%	0.5%	1.0%	1.1%
Coal	29.9%	0.6%	4.3%	0.6%	1.0%	1.0%	0.5%	0.4%	1.4%
Natural Gas	17.2%	0.5%	2.8%	0.5%	0.0%	0.0%	0.4%	0.1%	0.5%
Other	0.6%	-9.3%	7.8%	11.1%	23.3%	23.3%	4.4%	0.2%	0.2%
Missing Sources	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.4%
Total	82.9%	1.1%	3.7%	0.6%	1.2%	1.2%	0.5%	1.7%	3.5%
Methane									
Energy-Related	3.2%	13.2%	14.0%	4.9%	20.8%	25.0%	4.5%	0.8%	0.9%
Agricultural	2.8%	3.1%	5.0%	3.0%	36.4%	36.4%	10.6%	1.1%	1.1%
Industrial & Waste	3.2%	9.7%	29.4%	5.0%	50.5%	13.8%	10.1%	1.6%	1.1%
Missing Sources	0.0%	0.0%	4.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	9.2%	8.9%	20.6%	4.3%	35.9%	24.6%	8.3%	3.5%	3.1%
Nitrous Oxide									
Energy-Related	1.3%	0.5%	2.8%	0.5%	55.0%	200.0%	10.0%	0.7%	2.5%
Agricultural	4.1%	4.0%	5.0%	4.5%	90.0%	100.0%	10.0%	3.7%	4.1%
Industrial & Waste	0.4%	2.8%	5.0%	3.5%	55.0%	200.0%	10.0%	0.1%	0.5%
Missing Sources	0.0%	0.0%	15.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%
Total	5.7%	3.1%	19.5%	3.5%	80.0%	128.5%	10.0%	6.5%	7.5%
HFCs, PFCs, SF6									
HFCs, PFCs, SF6	2.2%	4.5%	2.4%	0.9%	13.8%	15.5%	2.5%	0.5%	0.6%
Missing Sources	0%	0.0%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%
Total	2.2%	4.5%	12.4%	0.9%	13.8%	15.5%	2.5%	0.5%	0.6%
Total-All Sources	**100.0%**	**2.0%**	**6.4%**	**1.1%**	**9.2%**	**11.0%**	**1.8%**	**13.2%**	**12.9%**

Notes: The “low” and “high” bias errors provide a subjective estimate of the largest bias error lower or higher than the current point estimate that would be consistent with current understanding of the nature of the activity or emissions mechanism. Each value is calculated as the weighted average of the uncertainties associated with a group of sources in each category. It is calculated as a percentage of the point estimate of emissions from that source. "Random error" is a subjective estimate of the largest random error that is consistent with current understanding of the nature of the activity or emissions estimate. "Weighted uncertainty" is calculated as the square root of the sum of the squared activity factor and emissions factor errors and then multiplied by the point estimate of the share of total emissions for the source. It is calculated as a percentage of the point estimate of total 1997 U.S. emissions.
Source: Estimates prepared for *Emissions of Greenhouse Gases In the United States 1997.*

The different sources of error, as noted above, can produce random or systematic (“bias”) errors. Random errors have the appearance of “noise” in the estimate, causing random year-to-year changes in the estimate as compared with (unobservable) actual emissions. Random errors might be caused by data collection and computation errors, the inherent imprecision of metering and measurement, and timing problems. Thus, it should be difficult to distinguish the “signal” of growing or declining emissions until the magnitude of the trend exceeds the “noise” from the random fluctuations. Since, in the case of U.S. energy data, rather small trends in the underlying data can be detected, it is likely that the aggregate magnitude of random errors in U.S. energy data is small, and, in particular, smaller than bias errors.

Bias errors will produce an error of approximately the same magnitude every year. If bias errors are small, they are not likely to affect the estimates of trends. Excluded sources and changes in definition produce bias errors. “Double counting” in activity data surveys will produce upwardly biased estimates of the activity; frame errors or other forms of undercounting will produce estimates that are biased downward. Because EIA, like other statistical agencies, produces data by approximately the same methods every year, double counting and undercounting errors are likely to persist over time.

There is no reason to believe that the distribution of bias errors is symmetrical around the point estimate of the value. In fact, *a priori* or independently gathered information may indicate that the potential size and probability of the existence of bias errors may be skewed: for example, in EIA data it is likely that essentially all the transactions reported to EIA actually occurred; however, it is possible that some transactions were never reported. Thus, EIA energy data are more likely to underestimate than to overestimate actual energy consumption. Further, because there are multiple surveys of energy production and consumption, undertaken for multiple purposes, the results of the surveys can help put bounds on the extent of possible bias errors.

Bias errors can be hard to detect, and it is hard to prove either the presence or absence of bias errors. The best ways of detecting them are to use multiple methods of estimating the source series and compare the results, or to determine the range of possible values from *a priori* information. Comparison methods usually can establish "ceilings" and "floors" for bias errors: that is, it is possible to demonstrate that if the bias error exceeded a certain percent, then a separate, independently collected series must also have a bias error of the same sign. An investigation of how the data are collected may also uncover information about the magnitude or scale of potential bias errors.

The reliability of emissions data varies by category and by source. In general, estimates of carbon dioxide emissions are more reliable than estimates for other gases. It is likely that the estimate of carbon dioxide emissions is accurate to within 5 percent. Estimates of methane emissions are much more uncertain. The level of uncertainty may exceed 30 percent. Estimates of methane emissions are also likely to understate actual emissions, as a result of the exclusion of sources that are unknown or difficult to quantify such as abandoned coal mines or industrial wastewater. Nitrous oxide emissions estimates are much more unreliable than carbon dioxide or methane emissions estimates, in part because nitrous oxide emissions have been studied far less than emissions from other sources and in part because the largest apparent sources of nitrous oxide emissions are area sources that result from biological activity, which makes for emissions that are highly variable and hard to measure or characterize. The uncertainty for nitrous oxide emissions may exceed 100 percent.

Tier 2 Analysis of Uncertainty in Greenhouse Gas Emissions

In order to carry out a Monte Carlo analysis, estimates of minimum, maximum and random bias in emission factors and activity data must be established. Table C2 shows the estimated bias and random uncertainties in activity data and emissions factors for carbon dioxide, methane and nitrous oxide delineated by fuel type and activity that was used in the Monte Carlo analysis. For petroleum, the activity data are divided into the following sectors: residential, commercial, and transportation (R,C,T); industrial; electric utility; and non-fuel use. For coal emissions, the division is between electric utility and other sectors (industrial combined with residential, commercial, and transportation). For natural gas emissions the division is the same as those for coal with the addition of flared gas. Methane and nitrous oxide emissions are divided by source categories. For each source category, bias and random errors are combined by assuming an aggregate emission factor and a single scaling factor for activity data.

Because the underlying data are obtained from various EIA surveys, they have different levels of associated uncertainty. For example, the maximum bias error for coal activity associated with electric utilities is estimated to be 4 percent, whereas the maximum bias error for coal activity associated with the other sectors is estimated to be 7 percent. This is because fuel use among the reporting electric power generators is relatively well known, but for the other sectors (especially residential and commercial) the data are less reliable.

Monte Carlo simulations were carried out for each greenhouse gas separately, as well as all greenhouse gases as a group. As such, each column of the Table C3 denotes a separate simulation. Uncertainty about the simulated mean varies by type of gas. There is less uncertainty around the carbon dioxide simulated mean (-1.4% to 1.3%) than methane (-15.6% to 16%) or nitrous oxide (-53.5% to 54.2%). If uncertainty is expressed as a percentage of estimated 1999 emissions, the uncertainty becomes more skewed in the positive direction. This follows from the bias error assumptions above that generally assume that emissions are underestimated. Denominating uncertainty as a percentage of estimated 1999 emissions yields the following uncertainty bands: carbon dioxide (-0.7% to 2.0%), methane (-2.8% to 33.7%) and nitrous oxide (-35.1% to 115.3%). If these uncertainty bands are expressed as a percentage of total estimated 1999 emissions[5], the following uncertainty bands are derived: carbon dioxide (-0.6% to 1.7%), methane (-0.3% to 3.4%) and nitrous oxide (-1.9% to 6.3%). The final column in the table shows the Monte

[5]Total 1999 emissions of carbon dioxide, methane and nitrous oxide as estimated in *EIA, Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99), October 2000.

Carlo results when all the gases are simulated together. This simulations shows that total uncertainty about the simulated mean is -4.4% to 4.6 percent. Expressed as a percentage of total emissions, the uncertainty is –0.4 to 9.0 percent.

Table C2. Random and Bias Uncertainties Associated with 1999 Inventory Data

Source Category	Activity Data Uncertainty			Emission Factor Uncertainty		
	BIAS (Uniform)		Random	BIAS (Uniform)		Random
	Min[a]	Max[b]	Mean	Min[a]	Max[b]	Mean
Carbon Dioxide						
NATURAL GAS						
Other Sectors (R,C,I,T)	0.5%	3.0%	0.5%	0.0%	0.0%	0.4%
Electric Utility	0.5%	2.0%	0.5%	0.0%	0.0%	0.4%
Flared	10.0%	25.0%	2.0%	10.0%	10.0%	5.0%
COAL						
Other Sectors (R,C,I,T)	1.00%	7%	0.70%	1%	1%	0.5%
Electric Utility	0.50%	4%	0.60%	1%	1%	0.5%
PETROLEUM						
R,C,T Sectors	2.0%	2.5%	0.5%	1.0%	1.0%	0.5%
Industrial	2.0%	3.0%	0.6%	4.0%	4.0%	0.6%
Electric Utility [Heavy Oil,Light Oil,Petroleum Coke]	0.5%	2.0%	0.5%	3.0%	3.0%	0.6%
Non-Fuel Use	1.0%	4.0%	0.6%	3.0%	3.0%	0.6%
U.S. TERRITORIES	5.0%	10.0%	5.0%	1.0%	1.0%	0.5%
CO2 IN NATURAL GAS	5.0%	5.0%	5.0%	30.0%	30.0%	5.0%
BUNKERS	10.0%	10.0%	0.2%	1.0%	1.0%	2.0%
CEMENT	2.0%	4.0%	1.0%	3.0%	3.0%	1.0%
OTHERS INDUSTRIAL SOURCES	5.0%	10.0%	3.0%	5.0%	5.0%	5.0%
Methane						
COAL						
Underground Coal Mines-Very “Gassy”	5.0%	10.0%	20.0%	0.0%	0.0%	0.0%
Degasification & Underground Mines	5.0%	10.0%	20.0%	35.0%	25.0%	5.0%
Surface Mines & Post-mining Emissions	10.0%	10.0%	10.0%	40.0%	100.0%	10.0%
OIL AND GAS SYSTEMS						
Natural Gas Systems	3%	5%	3%	40%	40%	5%
Petroleum Systems	3%	5%	3%	50.0%	60.0%	5.0%
COMBUSTION						
R&C Wood	10.0%	30.0%	5.0%	90.0%	200.0%	15.0%
Other Stationary & Mobile Combustion	0.5%	2.8%	0.5%	30.0%	30.0%	15.0%
WASTE HANDLING						
Landfills - Recovery Systems. (Modeled)	5.0%	20.0%	10.0%	25.0%	25.0%	10.0%
Landfills - Recovery Systems in Place (1992)	10.0%	10.0%	7.0%	0.0%	0.0%	0.0%
Landfills no Recovery Systems	10.0%	30.0%	5.0%	50.0%	10.0%	10.0%
Wastewater Systems	0.0%	3.0%	5.0%	55.0%	200.0%	10.0%
AGRICULTURAL SOURCES						
Livestock - Enteric Fermentation	3.0%	5.0%	3.0%	10.0%	10.0%	10.0%
Livestock Waste	3.0%	5.0%	3.0%	30.0%	40.0%	10.0%
Rice	5.0%	5.0%	3.0%	60.0%	60.0%	20.0%
Crop Residues	5.0%	5.0%	3.0%	60.0%	60.0%	20.0%
INDUSTRIAL PROCESSES						
Chemicals and Steel & Iron	3.00%	5%	3.00%	60%	60%	10.0%
Nitrous Oxide						
AGRICULTURAL SOURCES						
Nitrogen Fertilization	5.0%	10.0%	5.0%	90.0%	200.0%	10.0%
Animal Waste	3.0%	5.0%	3.0%	90.0%	100.0%	10.0%
Crop Residues	5.0%	10.0%	3.0%	60.0%	60.0%	20.0%
ENERGY COMBUSTION						
R&C Wood	10.0%	30.0%	5.0%	90.0%	200.0%	15.0%
Other Stationary Combustion	0.5%	2.8%	0.5%	55.0%	200.0%	10.0%
Waste Combustion	30.0%	30.0%	10.0%	90.0%	200.0%	15.0%
Mobile Sources	2.0%	2.5%	0.5%	1.0%	1.0%	0.5%
WASTE MANAGEMENT	2.0%	5.0%	5.0%	55.0%	200.0%	10.0%
INDUSTRIAL PROCESSES	10.0%	10.0%	3.0%	55.0%	200.0%	10.0%

a: The minimum bias is the relative change below the mean value.
b: The maximum bias is the relative change above the mean value.
Key: R,C,T, I: Residential, Commercial, Transportation, and Industrial; GHG: Greenhouse Gases.
Source: EIA-DOE annual data for 1999. Inventory Database.

Table C3. Preliminary Results of the Tier 2 Monte Carlo Uncertainty Analysis of EIA's Reported Greenhouse Gas Inventory Data, 1999
Based on 1999 Data (Million Metric Tons of Carbon Equivalent, MMTCe)

	Carbon Dioxide	Methane	Nitrous Oxide	Total
Estimated 1999 Value	1526.8	180.7	98.8	1806.3
Monte Carlo Simulated 1999 Mean	1536.4	208.2	138.0	1882.2
5th Percentile	1515.5	175.6	64.2	1799.5
95th Percentile	1556.8	241.5	212.8	1969.6
Total Uncertainty Around Simulated Mean	41.3	65.9	148.6	170.1
Uncertainty as Percent of Simulated Mean	-1.4% to 1.3%	-15.6% to 16.0%	-53.5% to 54.2%	-4.4% to 4.6%
Uncertainty as Percent of Estimated Value	-0.7% to 2.0%	-2.6% to 33.7%	-35.1% to 115.3%	-0.4% to 9.0%
Uncertainty as Percent of Total Estimated Emissions	-0.6% to 1.7%	-0.3% to 3.4%	-1.9% to 6.3%	-0.4% to 9.0%

[a]Estimated 1999 emissions from EIA, *Emissions of Greenhouse Gases in the United States 1999*, DOE/EIA-0573(99), October 2000.
[b]Monte Carlo simulations using 1999 EIA data from Science Applications International Corporation, prepared for the Energy Information Administration, Monte Carlo Simulations of Uncertainty in U.S. Greenhouse Gas Emissions and Related Support Work, May 2001.
[c]Expressed as a percentage of total carbon dioxide, methane and nitrous oxide emissions in 1999. Note, that this excludes HFC, PFC and SF6 emissions as these were not included in the uncertainty analysis.
[d]Note that, with the exception of estimated 1999 values, rows will not sum to total because each individual row denotes a separate simulation. Monte Carlo simulations were carried out for each pollutant separately, as well as a group.

Uncertainty of Carbon Coefficients Used in This Report

Because carbon dioxide emissions are such a large component of total greenhouse gas emissions, EIA has undertaken a review and update of the carbon coefficients for fossil fuels that when combined with combustion factors produce the emission factor for that fuel. A discussion of the uncertainty inherent in those factors is presented below.

Coal

Carbon coefficients for coal vary considerably by rank and state. Bituminous coal production and sub-bituminous coal production represented 53.4 percent and 38.1 percent of total U.S. supply in 2000, respectively. Carbon coefficients for bituminous coal vary from a low of 200.5 pounds carbon dioxide per million Btu in Kansas to a high of 232.0 pounds carbon dioxide per million Btu in Montana. In 2000, however, just 200 tons of bituminous coal were produced in Kansas and none were produced in Montana. In 2000, more than 60 percent of bituminous coal was produced in three states: West Virginia, Kentucky and Pennsylvania, and this share has remained fairly constant since 1990. These three states show a variation in carbon content for bituminous coals of ±0.7% that is based on more than 2,000 samples (See Table C4).

Similarly, the carbon coefficients for sub-bituminous coals range from 201.3 pounds carbon dioxide per million Btu in Utah to 217.5 pounds carbon dioxide per million Btu in Washington. Utah showed no sub-bituminous production in 2000 and Washington just 4,000 tons. Wyoming, however, has represented between 75 percent and 82 percent of total sub-bituminous coal production in the United States since 1990. Thus, the carbon content coefficient for Wyoming, based on 435 samples, dominates. The interquartile range of carbon content coefficients among samples of sub-bituminous coal in Wyoming was ±1.5% from the mean. Similarly this range among samples of bituminous coal from West Virginia, Kentucky, and Pennsylvania was ±1.0% or less for each State. The large number of samples and the low variability within the sample set of the states that represent the predominant source of supply for U.S. coals suggest that the uncertainty in this factor is very low, on the order of ±1.0%.

Table C4. Variability in Carbon Content Coefficients by Rank Across States
(Pounds Carbon Dioxide Per Million Btu)

State	Number of Samples	Bituminous	Sub-bituminous	Anthracite	Lignite
Alabama	946	204.7	-	-	218.5
Alaska	90	216.8	216.3	-	217.5
Arizona	11	-	215.0	-	-
Arkansas	70	212.8	-	-	209.4
Colorado	292	208.1	212.7	-	212.7
Georgia	35	209.5	-	-	-
Idaho	1	-	209.2	-	-
Illinois	16	205.8	-	-	-
Indiana	125	204.3	-	-	-
Iowa	89	202.7	-	-	-
Kansas	28	200.5	-	-	-
Kentucky	870	204.1	-	-	-
Louisiana	1	-	-	-	211.7
Maryland	46	208.0	-	-	-
Massachusetts	3	-	-	253.1	-
Michigan	3	204.7	-	-	-
Mississippi	8	-	-	-	216.5
Missouri	91	202.5	-	-	-
Montana	301	232.0	215.5	228.4	219.1
Nevada	2	208.1	-	-	220.1
New Mexico	167	210.0	209.2	229.1	-
North Dakota	186	-	-	-	219.5
Ohio	646	202.5	-	-	-
Oklahoma	46	204.3	-	-	-
Pennsylvania	739	205.9	-	228.5	-
Tennessee	58	204.6	-	-	-
Texas	48	-	-	-	208.9
Utah	152	211.8	201.3	-	-
Virginia	456	206.2	-	217.2	-
Washington	14	210.3	217.5	226.0	234.9
West Virginia	566	207.0	-	-	-
Wyoming	476	208.7	214.3	-	-

- (No Sample Data Available)
Source: U.S. Geological Survey, CoalQual Database Version 2.0 (1998) and analysis prepared by Science Applications International Corporation (SAIC) for the U.S. Environmental Protection Agency, Office of Air and Radiation, Market Policies Branch, October 2002.

Natural Gas

Pipeline-Quality

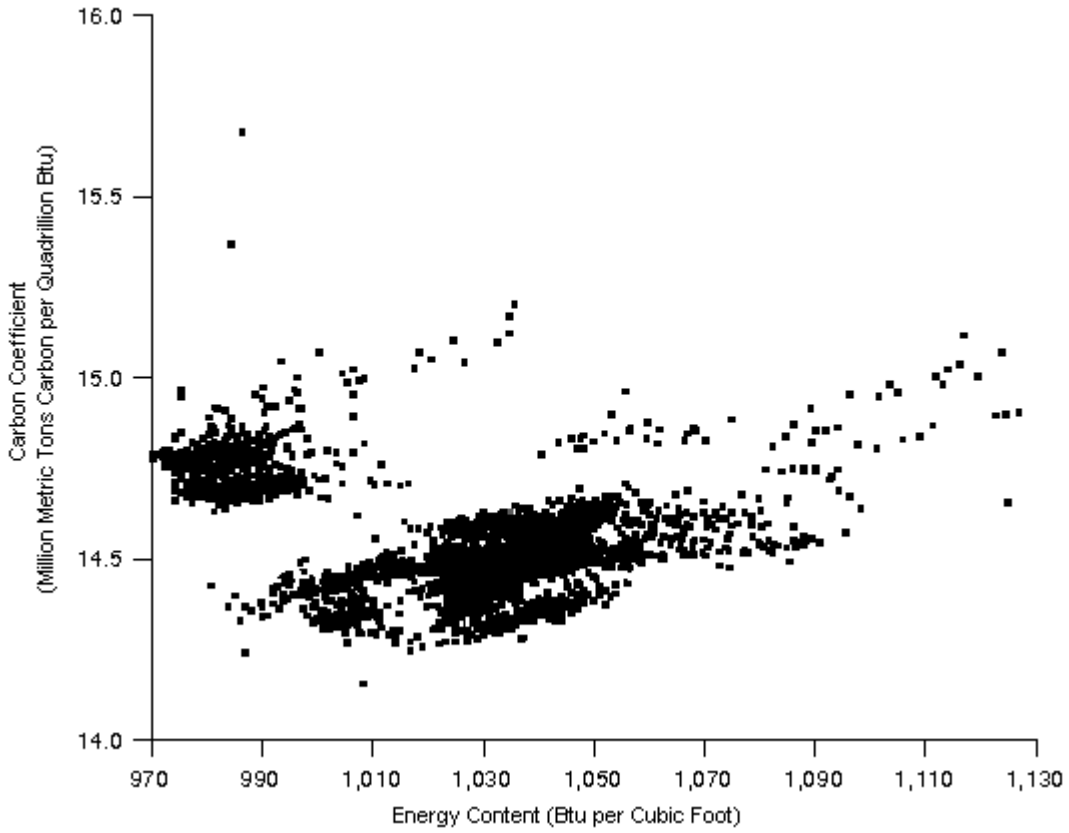
The EIA examined the composition of 6,743 samples of pipeline-quality natural gas from utilities and/or pipeline companies in 26 cities located in 19 States. Figure C1 shows the relationship between the calculated carbon coefficient for each natural gas sample and its energy content. This figure illustrates the relatively restricted range of variation in both the energy content (which varies by about 6 percent from average) and the carbon coefficient of natural gas (which varies by about 5 percent). Thus, the knowledge that gas has been sold via pipeline to an end use consumer allows us to predict its carbon coefficient with an accuracy of ±5.0%.

Natural gas suppliers may achieve the same energy contents with a wide variety of methane, higher hydrocarbon, and non-hydrocarbon gas combinations. Thus, the plot reveals large variations in carbon content for a single Btu value. In fact, the variation in carbon content for a single Btu value may be nearly as great as the variation for the whole sample. As a result, while energy content has some predictive value, the specific energy content does not substantially improve the accuracy of an estimated carbon content coefficient beyond the ±5.0% offered with the knowledge that it is of pipeline-quality.

The plot of carbon content also reveals other interesting anomalies. The samples with the lowest emissions coefficients tend to have energy contents of about 1,000 Btu per cubic foot. They are composed of almost pure methane. Samples with a greater proportion of natural gas liquids (NGLs) (e.g., ethane, propane, and butane) tend

to have energy contents greater than 1,000 Btu per cubic foot, along with higher emissions coefficients. Samples with a greater proportion of inert gases tend to have lower energy content, but they usually contain carbon dioxide as one of the inert gases and, consequently, also tend to have higher emissions coefficients (see left side of Figure C1).

Figure C1. Carbon Content for Samples of Pipeline-Quality Natural Gas Included in the Gas Technology Institute (Formerly Gas Research Institute) Database



Source: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1987-1992*,) DOE/EIA 0573, Appendix A (Washington, DC, November, 1994)

For the full sample (N=6,743), the average carbon content of a cubic foot of gas was 14.51 million metric tons per quadrillion Btu. However, this average was raised by both the samples with less than 1,000 Btu per cubic foot that contained large amounts of inert carbon dioxide and those samples with more than 1,050 Btu per cubic foot that contain an unusually large amount of NGLs. Because typical gas consumed in the U.S. does not contain such a large amount of carbon dioxide or natural gas liquids, a weighted national average of 14.47 million metric tons per quadrillion Btu that represents fuels more typically consumed is used.[6]

Flare Gas

Every year, a certain amount of natural gas is flared in the United States. There are several reasons that gas is flared:

- There may be no market for some natural gas associated with oil wells, as the amount may be too small or too variable, or the quality might be too poor to justify treating the gas and transporting it to market (such is the case when gas contains large shares of carbon dioxide). All natural gas flared for these reasons is probably "rich" associated gas, with relatively high energy content, high NGL content, and a high carbon content.

[6]The national average was weighted by applying the carbon content associated with the average heat content of natural gas consumed in each state by the portion of national natural gas consumption represented by that state.

- Gas treatment plants may flare substantial volumes of natural gas because of "process upsets," because the gas is "off spec," or possibly as part of an emissions control system. Gas flared at processing plants may be of variable quality.

Data on the energy content of flare gas, as reported by states to EIA, indicates an energy content of 1,130 Btu per standard cubic foot. Flare gas may have a higher energy content than reported by EIA because rich associated gas can have energy contents as high as 1,300 to 1,400 Btu per cubic foot. Rich associated gas will have a much higher proportion of natural gas liquids than pipeline natural gas. The most common NGLs are ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and, to a lesser extent, pentane (C_5H_{12}) and hexane (C_6H_{14}). Because the NGLs have more carbon atoms than methane (which has only one) their presence increases the overall carbon content of natural gas. Hexane is 83.7 percent carbon compared to the 75 percent carbon share found in methane.

Another important source of uncertainty associated with the carbon coefficient for flare gas is the definition of flare gas as reported to EIA by the States. EIA collects data on natural gas vented and flared without a clear distinction between gas flared and gas vented. For the purposes of this report all gas reported to EIA as vented or flared is assumed to be flared. Further, States may report a broad array of gases under the vented and flared category, some of which, such as hydrogen sulfide, are quite different in composition from the natural gas samples used for deriving the carbon coefficient adopted for this report. In some States, carbon dioxide that is vented is reported as vented and flared and its contribution to overall national emissions is not accurately reflected by treating it as combusted natural gas. Thus, there is a wide band of uncertainty associated with the carbon coefficient for flared natural gas.

Petroleum

Motor Gasoline and Motor gasoline Blending Components

There are two primary contributors to the uncertainty of carbon coefficients for motor gasoline. The first is the small number of motor gasoline samples and ultimate analyses from the work by Mark Deluchi.[7] However, the amount of variation in carbon content of gasoline is restricted by the compounds in the fuel to ± 4%. The second primary contributor to uncertainty is the assumed heat content. The heat contents are industry standards established many years ago. The heat contents are standard conversion factors used by EIA to convert volumetric energy data to energy units. Because the heat contents of fuels change over time, without necessarily and directly altering their volume, the conversion of known volumetric data to energy units may introduce bias. Thus, a more precise approach to estimating emissions factors would be to calculate carbon content per unit of volume, rather than per unit of energy. Adopting this approach, however, makes it difficult to compare U.S. carbon coefficients with those of other nations. The changes in density of motor gasoline over the last decade suggest that the heat content of the fuels is also changing. However, that change within any season grade has been less than 1% over the decade. Of greater concern is the use of a standardized heat content across grades which show a variation in density of ± 1.5%.

Jet Fuel

Variability in jet fuel is relatively small with the average carbon share of kerosene-based jet fuel varying by less than ± 1% and the density varying by ± 1%. This is because jet fuel is used to transport passengers long distances on commercial airliners. The ratio of fuel mass to useful energy must be tightly bounded to maximize safety and range. There is more uncertainty associated with the density and carbon share of naphtha-based jet fuel because sample data were unavailable and default values were used. This uncertainty has only a small impact on the overall uncertainty of the carbon coefficient for jet fuels, however, because naphtha-based jet fuel represents a small and declining share of total jet fuel consumption in the United States.

Distillate Fuel

The primary source of uncertainty for the estimated carbon coefficient of distillate fuel is the selection of No.2 fuel oil as the typical distillate fuel. No.2 fuel oil is generally consumed for home heating. No.1 fuel oil is generally less dense and if it is consumed in large portions for mobile sources, the carbon content estimated for this report is likely to be too high. The five No.1 fuel oil samples obtained by EIA contained an average of 86.01 percent carbon

[7] DeLuchi, Mark, *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity,* Volume 2, ANL/ESD/TM-22, Vol. 2 (Chicago, IL: Argonne National Laboratory, November 1993).

compared to the 86.34 percent contained in samples of No.2 fuel oil. A carbon coefficient based on No.1 fuel oil would equal 19.72 million metric tons per quadrillion Btu rather than the 19.95 million metric tons per quadrillion Btu for No.2 fuel oil. There is also small uncertainty in the share of carbon based on the limited sample size of ± 1 percent.

Residual Fuel

The largest source of uncertainty for estimating the carbon coefficient of residual fuel centers on the estimates of density, which differ from power generation to marine vessel fuels. The difference between the density implied by the energy content of electric power sector fuels and the density observed in the NIPER surveys is probably due to nonsulfur impurities, which reduce the energy content without greatly affecting the density of the product. Impurities of several percent are commonly observed in residual oil. The presence of these impurities also affects the share of the fuel that is carbon. Overall, the uncertainty associated with the carbon coefficient of residual fuel is probably ± 1%.

Liquefied Petroleum Gases

Because LPG consists of pure paraffinic compounds whose density, heat content and carbon share are physical constants, there is limited uncertainty associated with the carbon coefficient for this petroleum product. Overall uncertainty is derived mainly from the collection of consumption data and non-fuel data in U.S. energy statistics. This uncertainty is probably less than ± 3%.

Aviation Gasoline

The uncertainty associated with the carbon content coefficient for aviation gasoline is larger than that for other liquid petroleum products examined because no ultimate analyses of samples were conducted. However, given the requirements for safe operation of piston-powered aircraft the composition of aviation gas is well bounded and the uncertainty of the carbon coefficient is likely to be ± 5%.

Still Gas

Because the composition of still gas is highly heterogeneous, the carbon coefficient for this product is highly uncertain, with an accuracy of ± 33%. The carbon coefficient used for this report is probably at the high end of the plausible range.

Asphalt

The share of carbon in asphalts ranges somewhat broadly from 79 percent to 88 percent by weight with the remainder of the mixture also being variable; hydrogen shares vary by weight from seven to 13 percent and sulfur shares vary from trace levels to eight percent. Because carbon share and total heat content in asphalts do vary systematically, the overall carbon coefficient is likely to be accurate to ± 5%.

Lubricants

Uncertainty in the estimated carbon coefficient for lubricants is driven by the large range of product compositions and end uses in this category combined with an inability to establish the shares of the various products captured under this category in U.S. energy statistics. Because lubricants may be produced from either the distillate or residual fractions during refining, the possible carbon content coefficients range from just under 20.0 million metric tons per quadrillion Btu to about 21.5 million metric tons per quadrillion Btu, or an uncertainty band from – 1% to + 6% of the estimated value.

Petrochemical Feedstocks

Petrochemical feedstocks are not so much distinguished on the basis of chemical composition as on the identity of the purchaser, who may be presumed to be a chemical company or petrochemical unit co-located on the refinery grounds. This produces a considerable degree of uncertainty about the exact composition of petrochemical feedstocks. Since the carbon coefficient for petrochemical feedstocks is a weighted average of the coefficients for

naphtha and some class of middle distillates, the accurate coefficient is likely bounded by the two individual coefficients suggesting an uncertainty of ±6%.

Kerosene

Uncertainty in the estimated carbon coefficient for kerosene is driven by the selection of No. 1 fuel oil as a proxy for kerosene. If kerosene is more like kerosene-based jet fuel, the true carbon coefficient is likely to be some 2 percent lower. If kerosene is more aptly compared to No. 2 fuel oil, then the true carbon content coefficient is likely to be about 1 percent higher.

Petroleum Coke

The uncertainty associated with the estimated carbon coefficient of petroleum coke can be traced to two factors: the use of only two samples to establish carbon contents and a standard heat content which may be too low. Together, these uncertainties are likely to bias the carbon coefficient upwards by as much as 6 percent.

Special Naphtha

The principal uncertainty associated with the estimated carbon coefficient for special naphtha is the allocation of overall consumption across individual solvents. The overall uncertainty is bounded on the low end by the carbon content of hexane and on the upper end by the carbon content of high solvency mineral spirits. This implies an uncertainty band of –15 percent to + 6 percent.

Petroleum Waxes

Although there is considerable qualitative uncertainty associated with the allocation of petroleum waxes and microcrystalline waxes, the quantitative variation in the carbon contents for all waxes is limited to ± 1% because of the nearly uniform relationship between carbon and other elements in petroleum waxes broadly defined.

Crude Oil, Unfinished Oils and Miscellaneous

The uncertainty of the estimated carbon content for crude oil centers on the 35 percent of variation that cannot be explained by density and sulfur content. However, as crude is not currently directly consumed in the United States this does not add to the overall uncertainty of the U.S. emissions estimate. Because unfinished oils and miscellaneous products are difficult to define, the uncertainty of applying a crude oil carbon content is likely to be bounded by the range of petroleum products described in this chapter at ± 10%. This has a larger implication for the overall uncertainty of the emissions estimate than does crude oil directly. Miscellaneous products have been relatively stable in recent years with consumption in the range of 100 to 120 trillion Btu. However, in 2001, the volume of unfinished oils was estimated to contain an energy value of 69 trillion Btu, a value that is subtracted from the total supply disposition in order to avoid double counting with finished products. In 2000 this value was about 401 trillion Btu. Because this is a negative number in the energy consumption total, this fluctuation effectively added about one-third a quad of energy to the balance – or 6 million metric tons of carbon equivalent from 2000 to 2001. Therefore, the uncertainty associated with emission coefficients for unfinished oils could contribute to the overall uncertainty of the emissions estimate to a measurable degree.